Filing Receipt

Received - 2021-08-16 12:06:10 PM
Control Number - 52373
ItemNumber - 14

PROJECT NO. 52373

REVIEW OF WHOLESALE MARKET DESIGN	§ § §	PUBLIC UTILITY COMMISSION OF TEXAS

SOUTH TEXAS ELECTRIC COOPERATIVE, INC.'S COMMENTS

TO THE HONORABLE PUBLIC UTILITY COMMISSION OF TEXAS:

COMES NOW, South Texas Electric Cooperative, Inc. ("STEC") and submits the following Comments to the Public Utility Commission of Texas ("PUCT" or "Commission") regarding Commission Staff's Questions for Comment regarding wholesale market design changes. The deadline for the filing of Comments to be considered in the above-styled proceeding is August 16, 2021, therefore these Comments are timely filed.

I. INTRODUCTION

STEC supports and adopts the Comments filed by Texas Electric Cooperatives, Inc. ("TEC")[1] in response to the Commission Staff's Questions for Comment, and files these Comments supplementing the TEC Comments. Specifically, STEC's Comments make the following recommendations:

- The Commission should establish a target reliability benchmark prior to making changes to the existing market design.
- The Commission should consider increasing the Loss of Load Probability ("LOLP") in the ORDC by at least a 0.5 to 1.0 standard deviation.
- The ORDC should not be applied only to generators who commit in the Day Ahead Market ("DAM").
- ERCOT should not require a minimum offer to participate in the DAM.

[1] Comments of Texas Electric Cooperatives, Inc ("TEC Comments").

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- The Commission should increase the amount of ancillary services required from dispatchable generation and require ERCOT to thoughtfully and strategically increase the overall amounts of ancillary services procured.
- The cap for Emergency Response Service ("ERS") should not be increased.
- The Commission should consider implementing an administrative intermittent price adder that captures the cost of backstopping intermittent generation with thermal generation.

II. COMMENTS

1. **What specific changes, if any, should be made to the Operating Reserve Demand Curve (ORDC) to drive investment in existing and new dispatchable generation? Please consider ORDC applying only to generators who commit in the day-ahead market. Should that amount of ORDC-based dispatchability be adjusted to specific seasonal reliability needs?**

STEC recommends that the Commission determine a target reliability benchmark prior to making changes to the existing market design. Establishing a target level of reliability will assist the Commission and stakeholders in determining what policies are necessary to produce the desired outcome. STEC supports TEC's recommendation to use a "1-in-10" reliability standard that is structured to have no more than one load shed event within a ten-year period. Without a clear goal for reliability, the Commission will not have a benchmark by which to measure the success or failure of its policy reforms.

One improvement that can be made to the market to support reliability before setting a reliability benchmark is to make changes to the ORDC. There is ample information in previous dockets that the Commission should draw upon in informing its decision and as a result, incremental studies are not necessary for tweaks to be made. These changes can, and should, be made quickly. The Commission should consider increasing the Loss of Load Probability in the ORDC by at least a 0.5 to 1.0 standard deviation. If the current "conservative" operating posture of ERCOT is expected to endure beyond this year, then the PUCT should also investigate a rightward shift of the ORDC curve by modifying the value of X to capture ERCOT's more conservative approach. This would result in valuing reserves earlier, encouraging more commitment to generation through targeted revenue streams, and avoid the crisis-based market structure that we currently have.

STEC also recommends that the ORDC not be limited only to generators who offer or commit in the DAM. In the Real-Time Market ("RTM"), the ORDC currently serves as a proxy to more closely reflect market scarcity conditions that occur in markets with traditional supply and demand fundamentals where the supply and demand do not require the same instant balancing as is the case with electricity. Bifurcating the application of the ORDC results in the ORDC functioning more as a payment for capacity rather than a proxy market signal for all generation and would incorrectly and discriminatorily value DAM committed capacity differently than RTM committed capacity even though both types of capacity provide equivalent reliability benefits in real-time, particularly in times of system duress. The equivalent value of that capacity was never more evident than during the February winter storm.

If the Commission determines that a firm commitment of generation is needed to support reliability, that service should be compensated in a transparent, market-based manner for needed capacity through a capacity award payment. The amount of reserve capacity needed to support reliability can be adjusted seasonally. This reserved capacity would better support reliability in a manner consistent with the market design principals of the ERCOT market and would be consistent with the provisions of Senate Bill 3.

Finally, the Commission should continue to monitor the impact of real-time co-optimization ("RTC") implementation with respect to the ORDC. To maintain the level of revenues generated by the ORDC, the ancillary service demand curves developed in conjunction with RTC implementation must collectively preserve the existing or future level of benefits derived from the ORDC.

2. **Should ERCOT require all generation resources to offer a minimum commitment in the day-ahead market as a precondition for participating in the energy market?**

No. Requiring a minimum offer commitment will not add generation capacity to the overall fleet, will interfere with the fundamental principal that participation in the DAM is voluntary, and will drive out investment instead of incentivizing it.

Minimum offer requirements will not serve to increase reliability in the ERCOT system unless there is a mandatory bid requirement for load in the market to cause more generating resources to be committed in the DAM. It is well known that there are not sufficient energy bids in the DAM to represent the entire load of the ERCOT system. Absent a mandatory bid requirement for loads, there will not be any discernable incremental capacity committed by the DAM for real-time operation. Further, a mandatory offer requirement may have the unintended consequence of reducing generation supply by creating uncompensated obligations to provide generation capacity. A minimum offer requirement is a requirement to provide capacity that is not compensated for in the ERCOT energy-only market. A mandatory DAM offer construct may also harm peaking to intermediate unit commitment in the DAM because base load, or low operating cost resources, often currently forego the DAM in favor of self-commitment. Forcing those generation resources to offer into the DAM, particularly without a corresponding load bidding requirement, will displace and reduce the commitment of peaking assets and thereby cause ERCOT to more frequently RUC units—an out of market solution that further distorts the market prices for needed generation and creates a de facto capacity market for a subset of generation that is committed by RUC. Other markets have implemented DAM must-offer requirements, but those requirements are coupled with capacity markets or capacity obligations that provide a revenue stream in exchange for the must-offer requirement, and in most cases exist in areas where vertically integrated, fully regulated models are the dominant model.

There are also physical, contractual, economic and environmental limitations that exist for all resources that may conflict with a mandatory offer in the DAM. Valid reasons that a generation resource may forego offering into the DAM include: (i) the lack of need to do so for non-cycling base load units, (ii) units experiencing mechanical problems that threaten their availability (i.e. a mandatory offer requirement may create a DAM obligation that the generator might not be able to fulfill in the RTM), (iii) renewable generation forecast uncertainty that may lead to over-commitment and further reduce prices, (iii) credit management limitations or strategies, (iv) emissions or other permit limits, or (v) quick start units that do not need the benefit of DAM awards to inform their commitment.

(a) If so, how should that minimum commitment be determined?
(b) How should that commitment be enforced?

3. **What new ancillary service products or reliability services or changes to existing ancillary service products or reliability services should be developed or made to ensure reliability under a variety of extreme conditions? Please articulate specific standards of reliability along with any suggested AS products. How should the costs of these new ancillary services be allocated.**

STEC recommends that the Commission increase the amount of ancillary services required from dispatchable generation and require ERCOT to thoughtfully and strategically increase the overall amounts of ancillary services procured through the ancillary services markets. Ancillary service products should incentivize the development of a diverse generation fleet and should be priced at levels that provide financial incentives for generation to provide ancillary services. Decoupling ancillary service offers from a DAM physically binding commitment as part of RTC implementation will give ERCOT and market participants greater flexibility to move ancillary service awards to units that are best able to meet system needs as they occur in Real-Time, thereby reducing costs to consumers and allowing market participants to better respond to price signals.

The full implementation of NPRR 863 will provide ERCOT with sufficient tools to manage frequency related challenges.[2] Future ancillary service products should focus on resiliency and should contain requirements that achieve the desired end goal of fulfilling the objectives laid out in Senate Bill 3, including increasing fuel security (e.g. dual fuel or firm supplies of fuel) for assets that are weatherized. Furthermore, these additional tools should have a minimum duration performance level (e.g. 72 hours of continuous deliverability) in order for a resource to be eligible to provide that ancillary service. The Commission should avoid creating new ancillary services that are designed primarily to create a product for new technologies rather than to improve reliability.

4. **Is available residential demand response adequately captured by existing retail electric provider programs? Do opportunities exist for enhanced residential load response?**

   STEC has no comments at this time.

5. **How can ERCOT's emergency response service program be modified to provide additional reliability benefits? What changes would need to be made to Commission rules and ERCOT market rules and systems to implement these program changes?**

The cap for ERS participation should not be increased, particularly in light of the limited utility of the service as designed and implemented. Analysis of event performance during the February winter storm showed large differentials in ERS performance rates. ERCOT and the PUCT should continue to monitor the availability and event performance of ERS participants, particularly ERS participants that did not meet performance obligations during the storm. ERCOT

[2] Nodal Protocol Revision Request 863, *Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve Service* ("NPRR 863").

should review compliance metrics for availability and event-based performance and consider strengthening the metrics.

The Commission should also examine whether the current ERS framework offers adequate incentives for maintaining availability and performing when called upon. ERCOT data shows a strong historical tendency for ERS loads and generators to self-deploy in advance of an event. Self-deployment should be prohibited so that ERCOT can have confidence that it will receive the deployed amount when called upon. Availability metrics should be tightened, particularly for the alternate baseline, which is easy to pass without providing a true degree of certainty that the ERS resource will be available when called upon.

The contract term for ERS participation should be shortened along with the tightening of the ERS performance metrics. One option is for ERCOT to procure a monthly base amount of ERS with residual amounts procured daily. This could allow an opportunity for oversubscribed Load Resources to participate.

6. **How can the current market design be altered (e.g., by implementing new products) to provide tools to improve the ability to manage inertia, voltage support, or frequency?**

Having a diverse generation fleet is important for reliability because each type of technology brings distinct operational benefits. Maintaining fleet diversity should be a consideration in the development of new ancillary service products.

The Commission and ERCOT have previously considered developing an ancillary service product to capture the value of inertia. As traditional generation continues to exit the market, the need for synchronous generation increases and should be financially incentivized. However, implementation of an inertia ancillary service product alone will not be enough to maintain traditional generation in the market. Increasing overall pricing signals for dispatchable generation is necessary to incent existing and new entry synchronous generation market participants that are capable of providing inertia.

The Commission should consider implementing an administrative intermittent price adder that captures the cost of backstopping intermittent generation with thermal generation. This could be done similarly to how the Reliability Deployment Price Adder is determined with a subsequent pricing run for a calculated amount of renewable uncertainty (e.g., the difference between the P90 and P50 forecasts, or a similar methodology). This would be additive to the underlying locational marginal price and payable only to dispatchable generation with a defined operational minimum duration. The payment would be allocated on a cost-causation basis to the generation contributing to the need for ancillary services, thereby motivating such generators to firm up their energy production through the installation of energy storage resources or other mechanisms.

Finally, STEC suggests that current NERC and ERCOT frequency standards are sufficient, and a voltage support product is not needed at this time.

I. CONCLUSION

STEC appreciates the Commission's review of these important issues and respectfully requests the Commission's consideration of these Comments.

Respectfully submitted,

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